Chapter 1: Industry Profile

INTRODUCTION

This profile presents data for the electric power generating industry important for understanding the context of the analyses presented in this document. The majority of this profile is excerpted from Chapter A3 of the *Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule* (the "EBA"). For more information on aspects of the industry that may influence the nature and magnitude of economic impacts of the Proposed Section 316(b) Phase II Existing Facilities Rule, see Chapter A3 of the EBA.

The electric power industry is one of the most extensively studied industries. The Energy Information Administration (EIA), among others, publishes a multitude of reports, documents, and studies on an annual basis. This profile is not intended to duplicate those efforts. Rather, this profile compiles, summarizes, and presents those industry data that are important in the context of the proposed Phase II rule. For more information on general concepts, trends, and developments in the electric power industry, the last section of this profile, "References," presents a select list of other publications on the industry.

The remainder of this profile is organized as follows:

- Section 1-1 provides a brief overview of the industry, including descriptions of major industry sectors and types of generating facilities.

- Section 1-2 provides data on industry production and capacity.

- Section 1-3 focuses on the in-scope section 316(b) facilities. This section provides information on the geographical, physical, and cooling water characteristics of the in-scope phase II facilities.

1-1 INDUSTRY OVERVIEW

This section provides a brief overview of the industry, including descriptions of major industry sectors and types of generating facilities.

1-1.1 Industry Sectors

The electricity industry is made up of three major functional service components or sectors: *generation*, *transmission*, and *distribution*. Each of these terms are defined as follows (Beamon, 1998; Joskow, 1997):[1]

- The ***generation*** sector includes the power plants that produce, or "generate," electricity.[2] Electric energy is produced using a specific generating technology, for example, internal combustion engines and turbines. Turbines can be driven by wind, moving water (hydroelectric), or steam from fossil fuel-fired boilers or nuclear reactions. Other methods of power generation include geothermal or photovoltaic (solar) technologies.

[1] Terms highlighted in bold and italic font are defined in the glossary at the end of this chapter.

[2] The terms "plant" and "facility" are used interchangeably throughout this profile and document.

- The ***transmission*** sector can be thought of as the interstate highway system of the business – the large, high-voltage power lines that deliver electricity from power plants to local areas. Electricity transmission involves the "transportation" of electricity from power plants to distribution centers using a complex system. Transmission requires: interconnecting and integrating a number of generating facilities into a stable, synchronized, alternating current (AC) network; scheduling and dispatching all connected plants to balance the demand and supply of electricity in real time; and managing the system for equipment failures, network constraints, and interaction with other transmission networks.

- The ***distribution*** sector can be thought of as the local delivery system – the relatively low-voltage power lines that bring power to homes and businesses. Electricity distribution relies on a system of wires and transformers along streets and underground to provide electricity to residential, commercial, and industrial consumers. The distribution system involves both the provision of the hardware (for example, lines, poles, transformers) and a set of retailing functions, such as metering, billing, and various demand management services.

Of the three industry sectors, only electricity generation uses cooling water and is subject to section 316(b). The remainder of this profile will focus on the generation sector of the industry.

1-1.2 Prime Movers

Electric power plants use a variety of ***prime movers*** to generate electricity. The type of prime mover used at a given plant is determined based on the type of load the plant is designed to serve, the availability of fuels, and energy requirements. Most prime movers use fossil fuels (coal, petroleum, and natural gas) as an energy source and employ some type of turbine to produce electricity. The six most common prime movers are (U.S. DOE, 2000a):

- ***Steam Turbine:*** Steam turbine, or "steam electric" units require a fuel source to boil water and produce steam that drives the turbine. Either the burning of fossil fuels or a nuclear reaction can be used to produce the heat and steam necessary to generate electricity. These units are generally ***baseload*** units that are run continuously to serve the minimum load required by the system. Steam electric units generate the majority of electricity produced at power plants in the U.S.

- ***Gas Combustion Turbine:*** Gas turbine units burn a combination of natural gas and distillate oil in a high pressure chamber to produce hot gases that are passed directly through the turbine. Units with this prime mover are generally less than 100 megawatts in size, less efficient than steam turbines, and used for ***peakload*** operation serving the highest daily, weekly, or seasonal loads. Gas turbine units have quick startup times and can be installed at a variety of site locations, making them ideal for peak, emergency, and reserve-power requirements.

- ***Combined-Cycle Turbine:*** Combined-cycle units utilize both steam and gas turbine prime mover technologies to increase the efficiency of the gas turbine system. After combusting natural gas in gas turbine units, the hot gases from the turbines are transported to a waste-heat recovery steam boiler where water is heated to produce steam for a second steam turbine. The steam may be produced solely by recovery of gas turbine exhaust or with additional fuel input to the steam boiler. Combined-cycle generating units are generally used for ***intermediate loads***.

- ***Internal Combustion Engines:*** Internal combustion engines contain one or more cylinders in which fuel is combusted to drive a generator. These units are generally about 5 megawatts in size, can be installed on short notice, and can begin producing electricity almost instantaneously. Like gas turbines, internal combustion units are generally used only for peak loads.

- ***Water Turbine:*** Units with water turbines, or "hydroelectric units," use either falling water or the force of a natural river current to spin turbines and produce electricity. These units are used for all types of loads.

- ***Other Prime Movers:*** Other methods of power generation include geothermal, solar, wind, and biomass prime movers. The contribution of these prime movers is small relative to total power production in the U.S., but the role of these prime movers may expand in the future because recent legislation includes incentives for their use.

Table 1-1 provides data on the number of existing utility and nonutility power plants by prime mover. This table includes all plants that have at least one non-retired unit and that submitted Forms EIA-860A (Annual Electric Generator Report - Utilities) or EIA-860B (Annual Electric Generator Report - Nonutilities) in 1999.[3] For the purpose of this analysis, plants were classified as "steam turbine" or "combined-cycle" if they have at least one generating unit of that type. Plants that do not have any steam electric units, were classified under the prime mover type that accounts for the largest share of the plant's total electricity generation.

Table 1-1: Number of Existing Plants by Prime Mover, 1999

Prime Mover	Number of Plants
Steam Turbine	1,624
Combined-Cycle	260
Gas Turbine	707
Internal Combustion	887
Hydroelectric	1,713
Other	139
Total	**5,330**

Source: U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

Only prime movers with a steam electric generating cycle use substantial amounts of cooling water (for the condensing of steam exiting the steam turbines). These generators include steam turbines and combined-cycle technologies. As a result, the analysis in support of the proposed Phase II rule focuses on generating plants with a steam electric prime mover. This profile will, therefore, differentiate between steam electric and other prime movers.

[3] At the time of publication of this document, 1999 was the most recent year for which complete EIA data were available for existing utility and nonutility plants. As of March 2002, EIA 860B data were not available for year 2000. As such, this profile is based on 1999 data.

1-2 Domestic Production

This section presents an overview of U.S. generating capacity and electricity generation. Subsection 1-2.1 provides data on capacity, and Subsection 1-2.2 provides data on generation. Subsection 1-2.3 presents an overview of the geographic distribution of generation plants and capacity.

1-2.1 Generating Capacity[4]

The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW). Capacity and capability are the two common measures (U.S. DOE, 2000a):

Nameplate capacity is the full-load continuous output rating of the generating unit under specified conditions, as designated by the manufacturer.

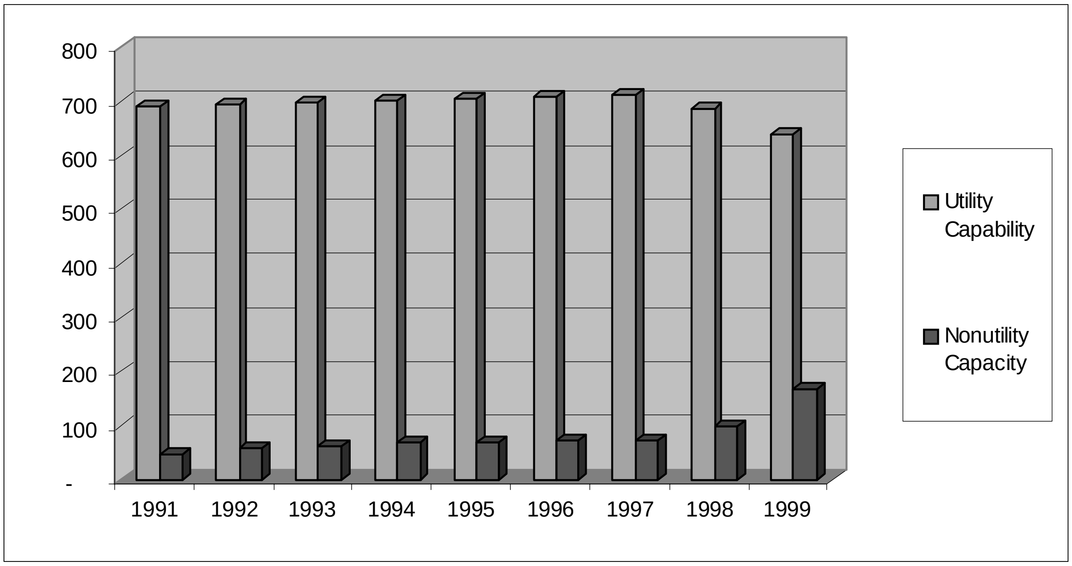
Net capability is the steady hourly output that the generating unit is expected to supply to the system load, as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause generating units to be less efficient. The nameplate capacity of a generating unit is generally greater than its net capability.

Figure 1-2 shows the total US generating capacity from 1991 to 1999.[5]

[4] The numbers presented in this section are *capability* for utility facilities and *capacity* for nonutilities. For convenience purposes, this section will refer to both measures as"capacity."

[5] More accurate data were available starting in 1991, therefore, 1991 was selected as the initial year for trends analysis.

Figure 1-2: Generating Capability & Capacity, 1991 to 1999[a]



Source: U.S. DOE, 2000c; U.S. DOE,1996b.

1-2.2 Electricity Generation

Total net electricity generation in the U.S. for 1999 was 3,723 billion kWh. Total net generation has increased by 21 percent over the nine-year period from 1991 to 1999.

Table 1-2 shows the change in net generation between 1991 and 1999 by fuel source for utilities and nonutilities.

Measures of Generation

The production of electricity is referred to as generation and is measured in ***kilowatthours (kWh)***. Generation can be measured as:

Gross generation: The total amount of power produced by an electric power plant.

Net generation: Power available to the transmission system beyond that needed to operate plant equipment. For example, around 7% of electricity generated by steam electric units is used to operate equipment.

Electricity available to consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

U.S. DOE, 2000a

Table 1-2: Net Generation by Energy Source, 1991 to 1999 (GWh)

Energy Source	Total		
	1991	1999	% Change

Coal	1,591	1,893	19%
Hydropower	286	315	10%
Nuclear	613	734	20%
Petroleum	119	108	-9%
Gas	392	592	51%
Renewables[b]	67	80	19%
Total	**3,067**	**3,723**	**21%**

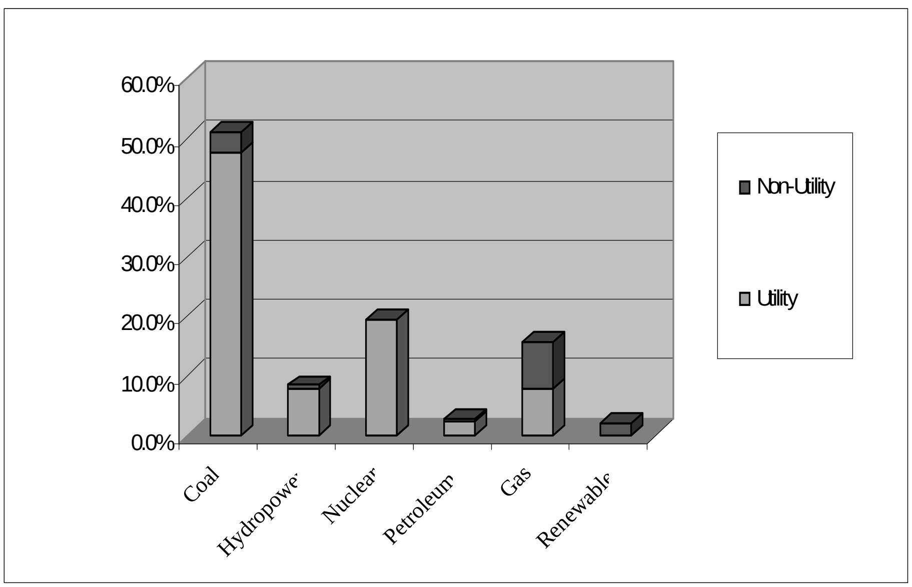
[a] Nonutility generation was converted from gross to net generation based on prime mover-specific conversion factors (U.S. DOE, 2000c). As a result of this conversion, the total net generation estimates differ slightly from EIA published totals by fuel type.

[b] Renewables include solar, wind, wood, biomass, and geothermal energy sources.

Source: U.S. DOE, 2000b;U.S. DOE, 2000c; U.S. DOE, 1995a; U.S. DOE,1995b.

Figure 1-3 shows total net generation for the U.S. by primary fuel source. Electricity generation from coal-fired plants accounts for 47 percent of total 1999 generation. The second largest source of electricity generation is nuclear power plants, accounting for 20 percent of total generation. Another significant source of electricity generation is gas-fired power plants, which account for 16 percent of total generation.

Figure 1-3: Percent of Electricity Generation by Primary Fuel Source, 1999



Source: U.S. DOE,2000b; U.S. DOE,2000c.

Regulatory options cosidered for proposed Phase II rule affect facilities differently based on the fuel sources and prime movers used to generate electricity. As mentioned in Section 1-1.2 above, only prime movers with a steam electric generating cycle use substantial amounts of cooling water.

1-3 EXISTING PLANTS WITH CWIS AND NPDES PERMITS

Section 316(b) of the Clean Water Act applies to a point source facility that uses or proposes to use a cooling water intake structure water that directly withdraws cooling water from a water of the United States. Among power plants, only those facilities employing a steam electric generating technology require cooling water and are therefore of interest to this analysis. Steam electric generating technologies include units with steam electric turbines and combined-cycle units with a steam component.

The following sections describe existing power plants that would be subject to the proposed Phase II rule. The Proposed Section 316(b) Phase II Existing Facilities Rule applies to existing steam electric power generating facilities that meet all of the following conditions:

- They meet the definition of an existing steam electric power generating facility as specified in § 125.93 of this rule;
- They use a cooling water intake structure or structures, or obtain cooling water by any sort of contract or arrangement with an independent supplier who has a cooling water intake structure;
- Their cooling water intake structure(s) withdraw(s) cooling water from waters of the U.S., and at least twenty-five (25) percent of the water withdrawn is used for contact or non-contact cooling purposes;
- They have an NPDES permit or are required to obtain one; and
- They have a design intake flow of 50 MGD or greater.

The proposed Phase II rule also covers substantial additions or modifications to operations undertaken at such facilities. While all facilities that meet these criteria are subject to the regulation, this document focuses on 539 steam electric power generating facilities identified in EPA's 2000 Section 316(b) Industry Survey as being "in-scope" of this proposed rule. These 539 facilities represent 550 facilities nation-wide.[6] The remainder of this chapter will refer to these facilities as "existing section 316(b) plants."

Utilities and nonutilities are discussed in separate subsections because the data sources, definitions, and potential factors influencing the magnitude of impacts are different for the two sectors. Each subsection presents the following information:

- ***Plant size:*** This section discusses the existing section 316(b) facilities by the size of their generation capacity. The size of a plant is important

WATER USE BY STEAM ELECTRIC POWER PLANTS

Steam electric generating plants are the single largest industrial users of water in the United States. In 1995:

- steam electric plants withdrew an estimated 190 billion gallons per day, accounting for 39 percent of freshwater use and 47 percent of combined fresh and saline water withdrawals for offstream uses (uses that temporarily or permanently remove water from its source);
- fossil-fuel steam plants accounted for 71 percent of the total water use by the power industry;
- nuclear steam plants and geothermal plants accounted for 29 percent and less than 1 percent, respectively;
- surface water was the source for more than 99 percent of total power industry withdrawals;
- approximately 69 percent of water intake by the power industry was from freshwater sources, 31 percent was from saline sources.

USGS, 1995

[6] EPA applied sample weights to the 539 facilities to account for non-sampled facilities and facilities that did not respond to the survey. For more information on EPA's 2000 Section 316(b) Industry Survey, please refer to the Information Collection Request (U.S. EPA 2000).

because it partly determines its need for cooling water.

- ***Geographic distribution:*** This section discusses plants by NERC region. The geographic distribution of facilities is important because a high concentration of facilities with costs under a regulation could lead to impacts on a regional level. Everything else being equal, the higher the share of plants with costs, the higher the likelihood that there may be economic and/or system reliability impacts as a result of the regulation.

- ***Water body and cooling system type:*** This section presents information on the type of water body from which existing section 316(b) facilities draw their cooling water and the type of cooling system they operate. Cooling systems can be either once-through or recirculating systems.[7] Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

[7] Once-through cooling systems withdraw water from the water body, run the water through condensers, and discharge the water after a single use. Recirculating systems, on the other hand, reuse water withdrawn from the source. These systems take new water into the system only to replenish losses from evaporation or other processes during the cooling process. Recirculating systems use cooling towers or ponds to cool water before passing it through condensers again.

1-3.1 Existing Section 316(b) Utility Plants

EPA identified steam electric prime movers that require cooling water using information from the EIA data collection U.S. DOE, 1999a.[8] These prime movers include:

- Atmospheric Fluidized Bed Combustion (AB)
- Combined-Cycle Steam Turbine with Supplementary Firing (CA)
- Combined Cycle - Total Unit (CC)
- Steam Turbine – Common Header (CH)
- Combined-Cycle – Single Shaft (CS)
- Combined-Cycle Steam Turbine – Waste Heat Boiler Only (CW)
- Steam Turbine – Geothermal (GE)
- Integrated Coal Gasification Combined-Cycle (IG)
- Steam Turbine – Boiling Water Nuclear Reactor (NB)
- Steam Turbine – Graphite Nuclear Reactor (NG)
- Steam Turbine – High Temperature Gas-Cooled Nuclear Reactor (NH)
- Steam Turbine – Pressurized Water Nuclear Reactor (NP)
- Steam Turbine – Solar (SS)
- Steam Turbine – Boiler (ST)

Using this list of steam electric prime movers, and U.S. DOE, 1999a information on the reported operating status of units, EPA identified 862 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the section 316(b) Industry Surveys was used to determine that 416 of the 862 facilities operate a CWIS and hold an NPDES permit. Table 1-4 provides information on the number of utilities, utility plants, and generating units, and the generating capacity in 1999. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the part of the industry potentially affected by the proposed Phase II rule.

Table 1-4: Number of Existing Utilities, Utility Plants, Units, and Capacity, 1999

	Total[a]	Steam Electric[b]		Steam Electric with CWIS and NPDES Permit[c]	
		Number	% of Total	Number	% of Total
Utilities	891	315	35%	148	17%
Plants	3,125	862	28%	416	13%
Units	10,460	2,226	21%	1,220	12%
Nameplate Capacity (MW)	702,624	533,503	76%	344,849	49%

[a] Includes only generating capacity not permanently shut down or sold to nonutilities.
[b] Utilities and plants are listed as steam electric if they have at least one steam electric unit.
[c] The number of plants, units, and capacity was sample weighted to account for survey non-respondents.

[8] U.S. DOE, 1999a (Annual Electric Generator Report) collects data used to create an annual inventory of utilities. The data collected includes: type of prime mover; nameplate rating; energy source; year of initial commercial operation; operating status; cooling water source, and NERC region.

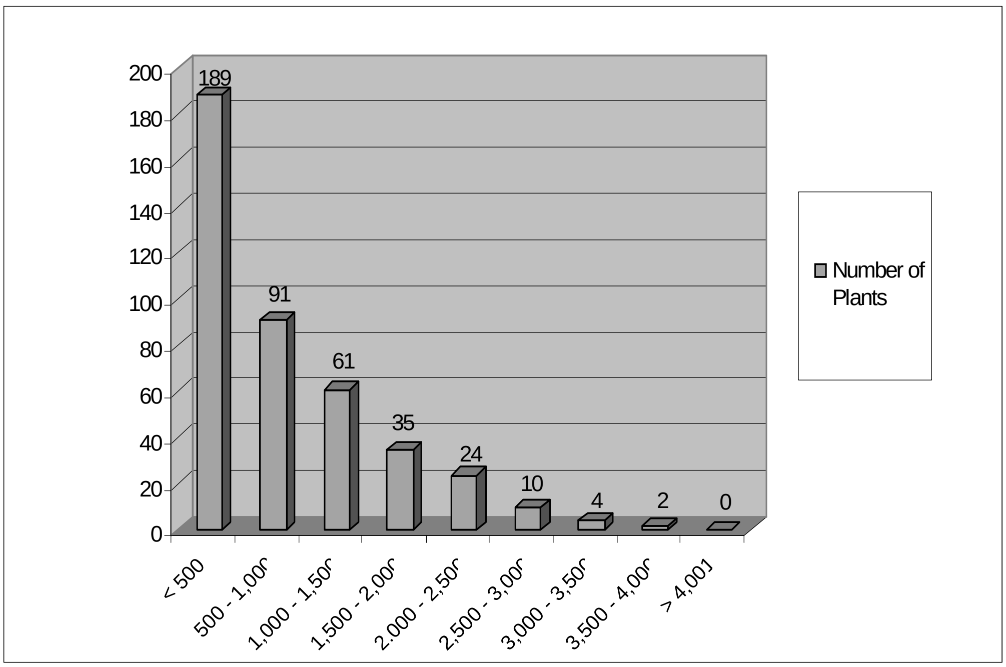
Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

Table 1-4 shows that the while the 862 steam electric plants account for only 28 percent of all plants, these plants account for 76 percent of all capacity. The 416 in-scope plants represent 13 percent of all plants, are owned by 17 percent of all utilities, and account for approximately 49 percent of reported utility generation capacity. The remainder of this section will focus on the 416 utility plants.

a. Plant size

EPA analyzed the utility steam electric facilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure 1-4 presents the distribution of existing utility plants with a CWIS and an NPDES permit by plant size. Of the 416 plants, 189 (45 percent) have a total nameplate capacity of 500 megawatts or less, and 280 (67 percent) have a total capacity of 1,000 megawatts or less.

Figure 1-4: Number of Existing Phase II Facilities by Plant Size (in MW), 1999 [a,b]



[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

b. Geographic distribution

Table 1-5 shows the distribution of existing section 316(b) utility plants by NERC region. The table shows that there are considerable differences between the regions in terms of both the number of existing utility plants with a CWIS and an NPDES permit, and the percentage of all plants that they represent. Excluding Alaska, which only has one utility plant with a CWIS and an NPDES permit, the percentage of existing section 316(b) facilities ranges from two percent in the Western Systems Coordinating Council (WSCC) to 49 percent in the Electric Reliability Council of Texas (ERCOT). The Southeastern Electric Reliability Council (SERC) has the highest absolute number of existing section 316(b) facilities with 94, or 23 percent of all facilities, followed by the East Central Area Reliability Coordination Agreement (ECAR) with 90 facilities, or 22 percent of all facilities.

Table 1-5: Existing Utility Plants by NERC Region, 1999

NERC Region	Total Number of Plants	Plants with CWIS and NPDES Permit[a,b]	
		Number	% of Total
ASCC	168	1	1%
ECAR	301	90	30%
ERCOT	107	52	49%
FRCC	62	29	47%
HI	16	3	19%
MAAC	93	3	3%
MAIN	207	33	16%
MAPP	406	43	11%
NPCC	394	17	4%
SERC	333	94	28%
SPP	262	32	12%
WSCC	773	18	2%
Unknown	3	0	0%
Total	**3,125**	**416**	**13%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: *U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.*

c. Water body and cooling system type

Table 1-6 shows that most of the existing utility plants with a CWIS and an NPDES permit draw water from a freshwater river (204, or 49 percent). The next most frequent water body types are lakes or reservoirs with 138 plants (33 percent) and estuaries or tidal rivers with 47 plants (11 percent). The table also shows that most of these plants, 314 or 75 percent, employ a once-through cooling system. Of the plants that withdraw from an estuary, the most sensitive type of water body, only nine percent use a recirculating system while 85 percent have a once-through system.

Table 1-6: Number of Existing Utility Plants by Water Body Type and Cooling System Type[a]

Water Body Type	Cooling System Type										Total [b]
	Recirculating		Once-Through		Combination		Other		Unknown		
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Estuary/ Tidal River	4	9%	40	85%	1	2%	2	4%	0	0%	**47**
Ocean	0	0%	15	100%	0	0%	0	0%	0	0%	**15**
Lake/ Reservoir	29	21%	103	75%	4	3%	2	1%	0	0%	**138**
Freshwater River	36	18%	149	73%	8	4%	10	5%	1	0%	**204**
Multiple Freshwater	0	0%	6	60%	3	30%	1	10%	0	0%	**10**
Other/ Unknown	1	50%	1	50%	0	0%	0	0%	0	0%	**2**
Total	**70**	**17%**	**314**	**75%**	**16**	**4%**	**15**	**4%**	**1**	**0%**	**416**

a The number of plants was sample weighted to account for survey non-respondents.
b Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

1-3.2 Existing Section 316(b) Nonutility Plants

EPA identified nonutility steam electric prime movers that require cooling water using information from the EIA data collection Forms EIA-860B[9] and the section 316(b) Industry Survey. These prime movers include:

- Geothermal Binary (GB)
- Steam Turbine – Fluidized Bed Combustion (SF)
- Solar – Photovoltaic (SO)

9 U.S. DOE, 1998b (Annual Nonutility Electric Generator Report) is the equivalent of U.S. DOE, 1998a for utilities. It is the annual inventory of nonutility plants and collects data on the type of prime mover, nameplate rating, energy source, year of initial commercial operation, and operating status.

- Steam Turbine (ST)

In addition, prime movers that are part of a combined-cycle unit were classified as steam electric.

U.S. DOE, 1998b includes two types of nonutilities: facilities whose primary business activity is the generation of electricity, and manufacturing facilities that operate industrial boilers in addition to their primary manufacturing processes. The discussion of existing section 316(b) nonutilities focuses on those nonutility facilities that generate electricity as their primary line of business.

Using the identified list of steam electric prime movers, and U.S. DOE, 1999b information on the reported operating status of generating units, EPA identified 559 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the section 316(b) Industry Survey determined that 134 of the 559 facilities operate a CWIS and hold an NPDES permit. Table 1-7 provides information on the number of parent entities, nonutility plants, and generating units, and their generating capacity in 1999. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the "section 316(b)" part of the industry.

Table 1-7: Number of Nonutilities, Nonutility Plants, Units, and Capacity, 1999

	Total	Total Steam Electric Nonutilities [a]	Nonutilities with CWIS and NPDES Permit[a,b]	
			Number	% of Steam Electric
Parent Entities	1,509	441	47	11%
Nonutility Plants	2,205	559	134	24%
Nonutility Units	5,958	1,255	343	27%
Nameplate Capacity (MW)	206,500	153,032	107,054	70%

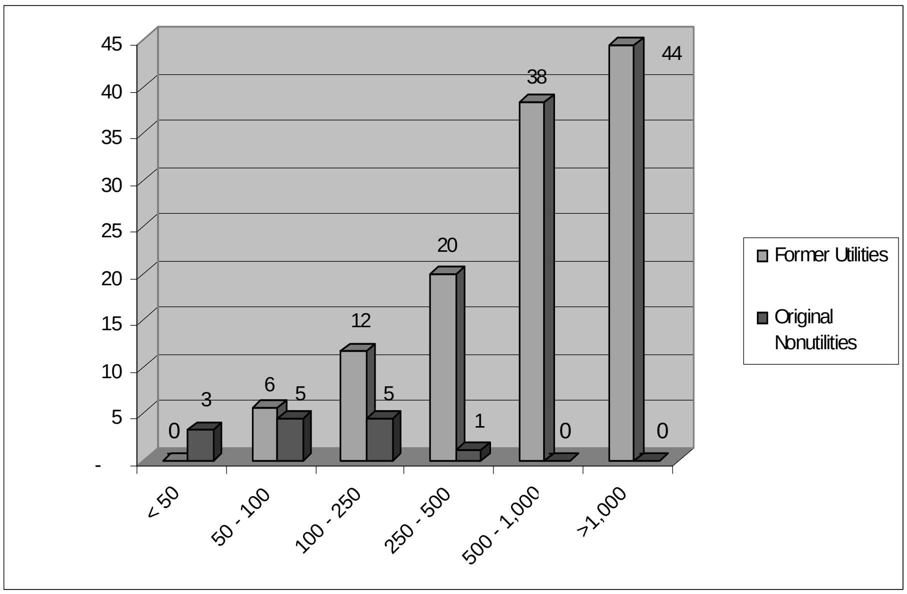
[a] Includes only nonutility plants generating electricity as their primary line of business.
[b] The number of plants, units, and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

a. Plant size

EPA analyzed the steam electric nonutilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure 1-5 shows that the original nonutility plants are much smaller than the former utility plants. Of the 14 original utility plants, 3 (25 percent) have a total nameplate capacity of 50 MW or less, and 8 (58 percent) have a capacity of 100 MW or less. No original nonutility plant has a capacity of more than 500 MW. In contrast, only 18 (15 percent) former utility plants are smaller than 250 MW while 83 (69 percent) are larger than 500 MW and 44 (37 percent) are larger than 1,000 MW.

Figure 1-5: Number of Existing Nonutility Plants with CWIS and NPDES Permit by Generating Capacity (in MW), 1998[a,b]



[a] Numbers may not add up to totals due to independent rounding.

[a] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

b. Geographic distribution

Table 1-8 shows the distribution of existing section 316(b) nonutility plants by NERC region. The table shows that the Northeast Power Coordinating Council (NPCC) has the highest absolute number of existing section 316(b) nonutility plants with 45 (9 percent) of the 134 plants with a CWIS and an NPDES permit, followed by the Mid-Atlantic Area Council (MAAC) with 41 plants. MAAC also has the largest percentage of plants with a CWIS and an NPDES permit compared to all nonutility plants within the region, at 26 percent.[10]

Table 1-8: Nonutility Plants by NERC Region, 1998

NERC Region	Total Number of Plants	Plants with CWIS & NPDES Permit[a,b]	
		Number	% of Total
ASCC	26	0	0%
ECAR	139	10	7%
ERCOT	75	0	0%
FRCC	57	1	2%
HI	11	0	0%
MAAC	155	41	26%
MAIN	136	18	13%
MAPP	70	1	2%
NPCC	531	45	9%
SERC	279	1	0%
SPP	43	0	0%
WSCC	613	16	3%
Not Available	70	0	0%
Total	**2,205**	**134**	**6%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

[10] The total number of plants includes industrial boilers while the number of plants with a CWIS and an NPDES permit does not. Therefore, the percentages are likely higher than presented.

c. Water body and cooling system type

Table 1-9 shows the distribution of existing section 316(b) nonutility plants by type of water body and cooling system. The table shows that a majority of plants with a CWIS and an NPDES permit draw water from either a freshwater river, or an estuary or tidal river.

The table also shows that most of the nonutilities employ a once-through system: 114 out of 133 nonutility plants. Of the plants that withdraw from an estuary/tidal river, the most sensitive type of waterbody, only two use a recirculating system, while 56 operate a once-through system.

Table 1-9: Number of Nonutility Plants by Water Body Type and Cooling System Type[a]

Water Body Type	Cooling System Type								
	Recirculating		Once-Through		Combination		Other		Total [b]
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Estuary/ Tidal River	2	3%	56	95%	1	2%	0	0%	59
Ocean	0	0%	9	100%	0	0%	0	0%	9
Lake/ Reservoir	2	17%	9	74%	1	9%	0	0%	12
Freshwater River	13	25%	39	75%	0	0%	1	2%	52
Other/ Unknown	0	0%	1	100%	0	0%	0	0%	1
Total	**17**	**13%**	**114**	**86%**	**2**	**2%**	**1**	**1%**	**133**

[a] The number of plants was sample weighted to account for survey non-respondents.
[b] Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

1-3.3 Cooling Water Intake Structure Data

A primary source of information used to prepare the analyses of this document is the 316(b) survey. The 316(b) survey was a two phase process. The results from the second phase of this process -- the distribution of questionnaires to utility and nonutility power producers -- is of specific interest to the analyses in this document. The results from following questionnaires are of interest to this proposed rule: (1) Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures -Traditional Steam Electric Utilities, (2) Short Technical Industry Questionnaire: Phase II Cooling Water Intake Structures - Traditional Steam Electric Utilities, (3) Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures - Steam Electric Nonutility Power Producers, and (4) Short Technical Industry Questionnaire: Phase II Cooling Water Intake Structures - Steam Electric Nonutility Power Producers. For the purposes of this document, the results of the detailed industry questionnaires for both utilities and nonutilities are addressed as simply the detailed questionnaire (the "DQ") results. Similarly, this document refers to the results from the short technical industry questionnaire for both utilities and nonutilities as simply the short technical questionnaire (the "STQ") results. Specific details about the questions may be found in EPA's Information Collection Request (DCN 3-3084-R2 in Docket W-00-03) and in the questionnaires (see DCN 3-0030 and 3-0031 in Docket W-00-03 and Docket for today's proposal); these documents are also available on EPA's web site (http://www.epa.gov/waterscience/316b/question/).

All utilities and a sample of nonutility facilities (those identified as in-scope by the results of a screener questionnaire) were sent either a STQ or a DQ. A total of 878 utility facilities and 343 nonutility facilities received one of the two questionnaires. EPA selected a random sample of these eligible facilities to receive a DQ. The sample included 282 utility facilities and 181 nonutility facilities. Those facilities not selected to receive a DQ were sent a STQ. More detail is provided in a report, Statistical Summary for Cooling Water Intakes Structures Surveys (See DCN 3-3077 in Docket W-00-03). Of the 282 utility facilities and 181 nonutility facilities receiving a DQ, the Agency determined that 225 of the respondents would fall within the scope of this rule. Of the STQ respondents, the Agency found that 314 would be in-scope.

The Agency compiled facility level, cooling system, and intake structure data for the 225 in-scope Detailed Questionnaire (DQ) respondents and, to the extent possible, for the 314 Short Technical Questionnaire (STQ) respondents. The Agency then used this tabulation of data to make determinations on the types of cooling systems and intake structures in-place at the in-scope facilities. The Agency utilized questions about intake systems common to both the DQ and STQ in order to make determinations about costing decisions that hinged on the intake structures in-place. Other pieces of information from the STQ provided insight into the types of intake structures in-place at the STQ facilities, when compared to more detailed information for the DQ respondents.

Using both the DQ and STQ responses, the Agency studied the intake structure characteristics for all 539 facilities and/or the 225 DQ facilities. The Agency focused on questions about intake screen structure types common to both the DQ and STQ. The Agency then examined the DQ respondents within the context of these questions to discern patterns and statistics for use in making decisions relating to costing of the proposed option based on intake systems currently in-place for both the DQ and STQ facilities. Tables 1-10 through 1-19 summarize this data analysis. For discussion and descriptions of the types of cooling water intake technologies presented in the tables, see Chapter 3 of this document.

Table 1-10 presents information for the in-scope, DQ respondents relating to the general configuration of their cooling water intake system, water body from which they withdraw cooling water, and cooling system type. The table also shows that the median intake velocity for all in-scope, DQ intakes is 1.5 feet per second. Of interest is the fact that of all in-scope DQ respondents, 89 percent of the intakes operate traveling screens and 25 percent report some form of impingement or entrainment reducing configuration.

Table 1-10 Statistics for all Detailed Questionnaire, In-scope Facilities

Percent	Cooling Water Intake Technology
22	cooling tower (recirculating or helper)
36	intake canal or channel
10	embayment/bay/cove
30	submerged shoreline intake
38	surface shoreline intake
14	submerged offshore intake
95	trash racks
97	intake screen
25	impingement / entrainment technology
5	passive intake
6	fish diversion or avoidance
32	fish handling and/or return
89	traveling screens
Percent	**Cooling System Type**
76	once-through
12	recirculating cooling
11	combination cooling
1	other cooling type
Percent	**Intake Velocity (median intake velocity = 1.5 ft/sec)**
14	velocity < or = 0.5 fps
Percent	**Waterbody Type**
22	Estuary/Tidal River
5	Ocean
49	Freshwater Stream/River
19	Lake/Reservoir
5	Great Lake

Table 1-11 shows similar information as in Table 1-10, however, the data is specific to the in-scope respondents to the DQ that reported impingement/ entrainment technologies. The cooling water intake technology information in the first portion of Table 1-11 resembles that of Table 1-10. However, the percentage of intakes with fish handling / fish return technologies is considerably higher for those reporting impingement / entrainment technologies compared to all in-scope DQ intakes. The distribution of cooling system types are similar for Tables 1-10 and 1-11, as is the median velocity.

Table 1-11 Statistics for DQ Intakes with Impingement / Entrainment Technologies

Percent	Cooling Water Intake Technology
22	cooling tower (recirculating or helper)
34	intake canal or channel
7	embayment/bay/cove
34	submerged shoreline intake
37	surface shoreline intake
5	submerged offshore intake
94	trash racks
98	intake screen
8	passive intake
2	fish diversion or avoidance
59	fish handling and/or return
Percent	**Cooling System Type**
80	once-through
14	recirculating cooling
5	combination cooling
1	other cooling type
Percent	**Intake Velocity (median intake velocity = 1.4 ft/sec)**
18	velocity < or = 0.5 fps
Percent	**Waterbody Type**
41	Estuary/Tidal River
4	Ocean
35	Freshwater Stream/River
19	Lake/Reservoir
2	Great Lake

Table 1-12 presents the number and capacity of the intakes for the in-scope DQ respondents. Key statistics, in the Agency's view, are the number of intakes per facility (less than two), the distribution of the number of intakes at in-scope DQ respondent facilities (64 percent with only one intake and only 11 percent of facilities with three or more intakes), and the average percent of intake flow used for cooling (86 percent).

Table 1-12. Number and Capacity of Intakes for In-Scope Detailed Questionnaire Facilities

Characteristic	Value
median design capacity per intake (gpd) for all intakes	219,000,000
median design capacity per facility (gpd) for all facilities	374,000,000
median capacity per intake (gpd) for facilities at or below median facility flow	100,800,000
median capacity per intake (gpd) for facilities above median facility flow	408,400,000
average number of intakes per facility for all facilities	1.6
Facilities with only 1 intake	64 %
Facilities with 2 or more intakes	36 %
Facilities with 3 or more intakes	11 %
Facilities at or below median facility flow with 2 or more intakes	26 %
Facilities above median facility flow with 2 or more intakes	46 %
Facilities at or below median facility flow with 3 or more intakes	4 %
Facilities above median facility flow with 3 or more intakes	17 %
Facilities at or below median facility flow with 4 or more intakes	1 %
Facilities above median facility flow with 4 or more intakes	8 %
Facilities with four or more intakes	4 %
Average number of intakes per facility at or below median facility flow	1.3
Average number of intakes per facility above median facility flow	1.8
Average percent of intake used for cooling per intake (all facilities)	86 %
Average percent of intake used for cooling for facilities at or below median flow	86 %
Average percent of intake used for cooling for facilities above median facility flow	87 %

Table 1-13 gives a breakdown of the type of fish handling / return systems at in-scope DQ facilities. Table 1-14 presents the same information, but only for the in-scope DQ respondents that reported both fish handling / fish return systems and impingement/ entrainment reducing configurations. Clearly, the most prevalent form of fish handling / return system is the conveyance system. See Chapter 3 of this document for descriptions of the types of fish handling / return systems.

Table 1-13. Statistics for DQ Facilities Reporting Fish Handling/Return Systems

Percent	Characteristic
8	fish pump
94	fish conveyance system
4	fish elevator/lift baskets
3	fish bypass
1	fish holding tank
3	other handling/return system
10	more than one of the above

Table 1-14. Statistics for Facilities Reporting Fish Handling / Returns AND Impingement / Entrainment Systems in Detailed Quetionnaire

Percent	Characteristic
14	fish pump
86	fish conveyance system
8	fish elevator/lift baskets
6	fish bypass
2	fish holding tank
6	other handling/return system
18	more than one of the above

Table 1-15 presents information for the in-scope DQ respondents that reported shoreline intakes (either surface or submerged intakes). Interestingly, the median surface water depth for surface and submerged shoreline intakes is very similar (approximately 18 feet). The percentage of in-scope DQ respondents with shoreline intakes is split, roughly equally, between submerged and surface configurations. The majority (77 percent) of all shoreline intakes are flush with the shore and only 8 percent protrude offshore.

Table 1-15. Statistics for Detailed Questionnaire Shoreline Intakes

characteristic	value
median surface water depth for both submerged and surface intakes (ft)	18
median surface water depth for surface intakes (ft)	17
median surface water depth for submerged intakes (ft)	18
median distance from top of intake to surface for all shoreline intakes (ft)	9
median distance from intake bottom to surface for all shoreline intakes (ft)	18
Percent of all shoreline intakes submerged	45
Percent of all shoreline intakes surface	55
Percent of all shoreline intakes flush with shore	77
Percent of all shoreline intakes recessed	15
Percent of all shoreline intakes protruding offshore	8
Percent of all shoreline intakes with skimmer/curtain/baffle wall	45

Tables 1-16 and 1-17 present basic information from the in-scope DQ respondents on the percent of fine-mesh screens and passive intakes in-place at these facilities. In addition, Table 1-16 includes the Agency's projection of the total number of fine-mesh screens at STQ respondents (note: the STQ did not collect information of sufficient detail to distinguish fine-mesh from coarse-mesh screens).

Table 1-16. Statistics for Fine Mesh Screens

Characteristic	Value
Detailed Questionnaire Intakes with Fine Mesh in-place	1.3 %
Detailed Questionniare Estuarine Intakes with Fine Mesh in-place	4.3%
Projected Number of Short Technical Questionnaire Intakes with Fine Mesh in-place	6

Table 1-17. Statistics for Passive Intake

Percent	Characteristic
5.4	Percent of All Intakes reported as Passive Intakes
5.3	Percent of Estuarine Intakes reported as Passive

Table 1-18 presents detailed information from the in-scope DQ respondents with offshore intakes. The percentage of impingement / entrainment technologies on offshore intakes is very low (2 percent). The median distance from shore is 450 feet and the median surface water depth is 30 feet at the intake. As expected, ocean intakes show the highest percentage of offshore configurations.

Table 1-18. Statistics for Intakes Reported as Offshore in the Detailed Questionnaire

Characteristic	Value
all DQ intakes Offshore	10
% of intakes reporting I/E Offshore	2
Median distance to shore for Offshore intakes (feet)	450
Median surface water depth at Offshore intake (feet)	30
Percent of estuarine intakes Offshore	5
Percent of ocean intakes Offshore	41
Percent of lake / Reservoir intakes Offshore	16
Percent of freshwater stream / river intakes Offshore	11
Percent of Great Lake intakes Offshore	35

Table 1-19 presents information for in-scope DQ intakes reporting canal or channel configurations. The median canal/channel length from mouth to pumps is 1000 feet. The cross-sectional water level ranges from 470 ft (median of reported low-water levels) to 620 ft (median of reported mean-water levels).

Table 1-19. Statistics for DQ Intakes Reporting Canal/Channel

Characteristic	Value
Median Length Canal Mouth to Pumps (ft)	1000
Median Intake X-Section-Low Water (ft)	472
Median Intake X-Section-Mean Water (ft)	617
Median Distance curtain/baffle from canal mouth (ft)	650
Median intake bay depth (ft)	17
Percent of canal/channel intakes with submerged shoreline Intakes	9 %
Percent of canal/channel intakes with surface shoreline intakes	19 %
Percent of canal/channel intakes with flush intakes	20 %
Percent of canal/channel intakes with recessed intakes	6 %
Percent of canal/channel intakes with protruding intakes	2 %

Glossary

Baseload: A baseload generating unit is normally used to satisfy all or part of the minimum or base load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Baseload units are generally the newest, largest, and most efficient of the three types of units. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Combined-Cycle Turbine: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Distribution: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electricity Available to Consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

Energy Policy Act (EPACT): In 1992 the EPACT removed constraints on ownership of electric generation facilities and encouraged increased competition on the wholesale electric power business.

Gas Combustion Turbine: A gas turbine typically consisting of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine. The hot gases expand to drive the generator and are then used to run the compressor.

Generation: The process of producing electric energy by transforming other forms of energy. Generation is also the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Intermediate load: Intermediate-load generating units meet system requirements that are greater than baseload but less than peakload. Intermediate-load units are used during the transition between baseload and peak load requirements. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Internal Combustion Engine: An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal fuel types used in these generators.

Kilowatthours (kWh): One thousand ***watthours (Wh)***.

Nameplate Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Net Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer, exclusive of station use, and unspecified conditions for a given time interval.

Net Generation: Gross generation minus plant use from all plants owned by the same utility.

Nonutility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Other Prime Movers: Methods of power generation other than ***steam turbine***, ***combined-cycle***, ***gas combustion turbine***, ***internal combustion engine***, and ***water turbine***. Other prime movers include: geothermal, solar, wind, and biomass.

Peakload: A peakload generating unit, normally the least efficient of the three unit types, is used to meet requirements during the periods of greatest, or peak, load on the system. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Power Marketers: Business entities engaged in buying, selling, and marketing electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission for status as a power marketer. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Power Brokers: An entity that arranges the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Prime Movers: The engine, turbine, water wheel or similar machine that drives an electric generator. Also, for reporting purposes, a device that directly converts energy to electricity, e.g., photovoltaic, solar, and fuel cell(s).

Public Utility Regulatory Policies Act (PURPA): In 1978 PURPA opened up competition in the electricity generation market by creating a class of nonutility electricity-generating companies referred to as "qualifying facilities."

Reliability: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Steam Turbine: A generating unit in which the prime mover is a steam turbine. The turbines convert thermal energy (steam or hot water) produced by generators or boilers to mechanical energy or shaft torque. This mechanical energy is used to power electric generators, including combined-cycle electric generating units, that convert the mechanical energy to electricity.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Water Turbine: A unit in which the turbine generator is driven by falling water.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under the pressure of 1 volt at unity power factor.(Does not appear in text)

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or take from, an electric circuit steadily for 1 hour. (Does not appear in text)

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